2.0 Trends affecting electric service costs

Overview

This section of the report describes trends affecting electric service costs for Washington consumers in six broad categories:

1. **Wholesale markets**
2. **Retail markets**
3. **Supply adequacy and reliability**
4. **Environment**
5. **Technology**
6. **Fuel cost**

This section will primarily address trends that affect total electric service costs. Trends and strategies that concern distribution of costs are covered more fully in Section 4, Electricity Rates and Equity: The Potential for Cost-shifting.

2.1 Wholesale markets

2.1.1 Federal Policy Changes and the Introduction of Wholesale Competition

Perhaps the most important and far-reaching trend affecting electric power costs is the change taking place in the market structure for power generation. Beginning in 1978 with the passage of the federal Public Utility Regulatory Policy Act (PURPA), non-utility generators have played a growing role in developing new power supplies. PURPA required investor-owned utilities to purchase power from non-utility generators if the price was less than the utility's own cost to build new generation. Although PURPA had a limited impact on most Washington utilities, it opened the door for companies other than utilities to build and own generation.

This change was accelerated by the passage of the federal Energy Policy Act in 1992. EPACT was intended to create a fully competitive wholesale market for generation, and spurred a number of developments that furthered that goal. One of these developments is the formation of regional transmission associations (RTAs) in the western interconnection to facilitate access to the regional transmission grid.

In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, "Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities". Order 888 requires transmission owners to offer transmission services to other companies under the same terms and conditions that they offer it to themselves. It also encourages the formation of independent system operators (ISOs) to provide open access to the transmission system under a grid-wide tariff that would apply to all eligible users. All jurisdictional utilities are required to file open access transmission tariffs with FERC that meet the specifications in the order, and to provide service to themselves and to other companies under the terms of those tariffs.

These developments have greatly increased the ability of generators to gain access to the transmission grid. The combination of these regulatory changes and low natural gas prices has resulted in increasingly active short-term markets for electric energy. Power is now traded on an hourly basis at trading hubs such as the Mid-Columbia bus, on a day-ahead basis on the California Power Exchange, and in the form of futures contracts on the New York Mercantile Exchange. Utilities now have a ready market in which to sell surplus generation to other utilities or to purchase power from other utilities or non-utility generators.

The development of active short-term markets, in conjunction with enhanced access to the transmission grid, may tend to lower the price of electric generation by maximizing the aggregate efficiency of the existing bulk power system. That is, an efficient market should help to ensure that whenever a low-cost resource and a high-cost resource are both available, the low-cost resource is called upon first. There is some evidence to suggest, however, that active short-term markets have increased utilization of resources with relatively high environmental costs.

One of the features of these markets is price volatility. Volatility may occur as prices continuously adjust to balance supply and demand at any given time. Electricity markets are likely to be particularly volatile, especially on an hourly basis, because electricity cannot be stored; so supply and demand must balance instantaneously. This means that utilities have very little time to arrange for alternate supplies in the event of an emergency. One such emergency occurred in the Midwest during June of 1998, when market prices soared to over $7.00 per kWh. This extreme volatility was caused by a series of extraordinary events including a heat wave, generating unit outages, transmission constraints, and defaults on power supply contracts by two power marketers. The combination caused confidence in the market to wane, leading to panic buying of whatever power was available.

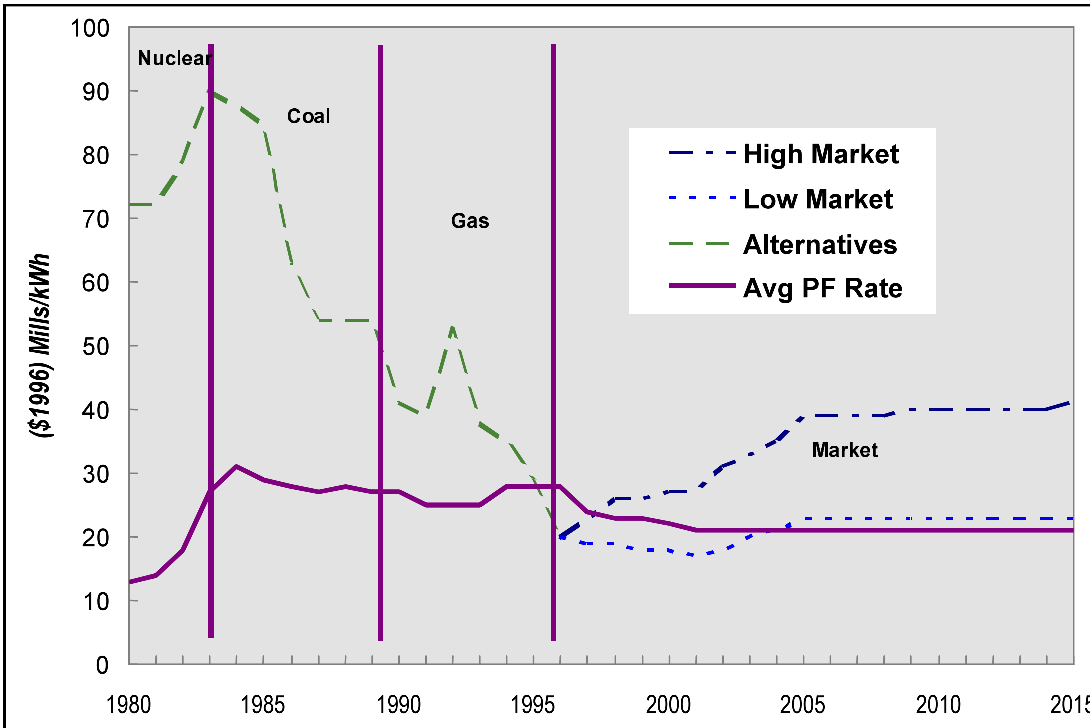
Volatility does not mean that power markets necessarily result in higher costs than traditional utility planning, in which enough capacity is built to meet an administratively determined probability of being able to meet all loads. Indeed, market volatility might result in capacity savings if price-sensitive customers (those that have the ability to modify their consumption based on price) purchase power on the open market. These customers would be free to make whatever arrangements they wished to hedge their risk against price volatility, while the utility would be freed from the obligation to manage the risk on behalf of those customers. On the whole, this may be a less costly way to balance supply and demand in peak periods than the traditional practice of building utility capacity to meet infrequent peak demands. It does, however, allow for conspicuous price swings.

2.1.2 Effects of wholesale competition on BPA and Federal Columbia River Power System

Although Washington has not initiated any significant changes in its retail market, Northwest states were among the first to experience significant effects from the introduction of wholesale competition. This is due to the tremendous importance of the Bonneville Power Administration in the region. BPA is a federal power marketing agency that operates exclusively at the wholesale level (with the exception of its Direct Service Industrial customers, to whom BPA provides retail service). The agency provides approximately half of the power consumed in Washington and operates 80% of the high voltage transmission in the State.

The effects of wholesale competition on BPA have been significant. As the graph below shows, the price of alternative power sources plummeted in the early 1990s, reaching and briefly falling below BPA's price in 1995. It is worth noting that this challenge to BPA's competitiveness does not appear to have been caused by increasing costs at BPA. BPA's prices have stayed virtually flat in nominal terms and declined somewhat in real terms since the dramatic increases associated with the WPPSS projects in the early 1980s. Competitive pressure was induced primarily by reductions in the price of alternative power sources.

Figure 2.1 Avoided Cost of Generation and Future Market Price Projections vs. BPA Average Rate



Sources: BPA Business Plan and 1996 Rate

When the price of alternative resources approached BPA prices, BPA embarked on a series of controversial changes in an effort to improve its competitive position. These changes included:

- ❖ Seeking a cap on fish and wildlife expenses and an exemption from any Endangered Species Act or other environmental requirements that would push fish and wildlife expenses higher.

- Terminating its contract to pay for construction and operation of the Tenaska gas-fired generating project.
- Reversing its preliminary commitment to British Columbia to purchase the “Canadian Entitlement” – power that returns to Canada under the terms of the Columbia River Treaty.
- Eliminating most of its energy efficiency investments.
- Large reductions in staff and contractors.
- Curtailing the Residential Exchange agreements through which BPA extended the benefits of the FCRPS to the residential and small farm customers of investor-owned utilities, including Puget Sound Energy.
- Developing new marketing strategies that were viewed by some as inappropriate competition with the private sector.
- Signing transmission contracts and power contracts with the Direct Service Industries that may preclude future recovery of stranded costs from those customers.

Each of these steps met with strong opposition from one or more stakeholder groups. With growing frequency throughout 1995, this opposition was brought to the attention of Congress and executive agencies in Washington, D.C.. Sensing that growing discord in the region was undermining the region’s ability to retain the benefits of the federal system for Northwest consumers, the Northwest Congressional delegation and the Department of Energy urged the four Northwest Governors to develop a plan for the future structure of the regional power system. In response, the Governors convened the Comprehensive Review of the Regional Energy System in 1996. The Steering Committee for the Comprehensive Review recommended a variety of changes with respect to the federal power system as a part of a package designed to balance competing interests. These changes included a strategy for marketing the output of the FCRPS to Northwest customers by subscription; formal separation of BPA’s transmission and generation functions; and formation of an independent system operator for the transmission system.

Since those recommendations were issued:

- The Northwest Power Planning Council convened a cost review panel to recommend further reductions in BPA’s costs. BPA has agreed to try to implement most of these recommendations. The final recommendations of the Cost Review are included as Appendix 2.1.
- The Governors appointed a Transition Board to oversee implementation of the Comprehensive Review’s recommendations. The Transition Board has focused on the recommendations with respect to BPA’s power and transmission operations. It has developed a proposal for recovering stranded costs in the event that BPA’s costs exceed market rates and a proposal for subjecting BPA’s transmission rates to review by the Federal Energy Regulatory Commission essentially equivalent to the review applied to investor-owned transmitting utilities.

- BPA will begin the process of offering subscriptions for cost-based power, according to the terms of a proposal issued in December of 1998.
- BPA is scheduled to begin a rate case that will further define the terms and conditions of those subscription contracts in 1999.

Another important trend affecting the region's ability to sustain the legal right to preferential access to cost-based power from the federal system is the growing pressure to redistribute the benefits of the FCRPS more broadly. This pressure has existed for decades. However the pressure may have intensified in recent years[1] due to a variety of factors, including:

- The evolution toward competition in wholesale, and, to a lesser extent, retail power markets. With power prices increasingly subjected to market forces, the rationale for continuing to constrain marketing of federal power at cost to a particular geographic region may appear to be eroding.
- The general trend in other countries and the U.S. away from large public enterprises and toward privatization.
- Growing concern over how to pay for the large federal entitlement programs as the population ages and the consequent pressure to convert federal assets to cash and/or increase the return to taxpayers from those assets.
- The increasingly organized advocacy of the Northeast-Midwest Coalition, a large group of members of Congress who call for selling federal power at market rates.
- The increasingly open nature of transactions throughout the Western power grid and the proliferation in the number of buyers and sellers seeking access to the lowest cost alternatives.
- The growing frequency with which regional power issues are debated in Washington, D.C. and the perception that federal taxpayers may be exposed to nuclear debt, fish costs, or other costs that BPA fails to recover in its rates.
- Recent improvement in BPA's market position, due in part to rising western wholesale market prices.

If these pressures converge in a way that allows redistribution of the benefits of the FCRPS, Washington's power prices could rise substantially. These pressures will almost certainly come to bear in the context of a national restructuring bill. They are likely to persist even in the absence of such a bill.

2.1.3 Effects of both wholesale and retail competition on the connection between existing generation and "native loads"

Historically, electric generating resources were built or purchased to serve a particular set of consumers. Those consumers had few, if any, options for electric service and their utilities were required to serve their loads. In this environment, consumers could generally expect to pay the costs and receive the benefits of a specific set of electric generating resources that were built to serve them.

With growing competition in both the wholesale and retail markets in the Western grid and major realignments of some vertically integrated utilities, this connection between customers and resources is becoming increasingly tenuous. Typically, the erosion of this connection has manifested itself as a "stranded cost" issue: When the connection between customer and resource is broken by competition, and the resource is worth less than it costs, who bears the portion of the costs that cannot be recovered through market rates ("stranded costs")? In Washington, the more significant issue may be on the other side of the coin: When the connection is broken, who reaps the benefits that accrue to resources that are worth more than they cost ("stranded benefits")?

Resolution of these questions may substantially affect the cost of electric service in Washington. These questions may have somewhat different implications for investor-owned and consumer-owned utilities, since the latter have no shareholders to bear stranded costs or reap stranded benefits. However, the prospect of redistribution of the benefits of low-priced resources is a concern for both types of utilities and their customers. Insofar as resources used to serve Washington consumers are below market, erosion of the connection between "native resources" and "native loads" will tend to increase costs for Washington consumers, unless measures are taken to preserve the financial benefits of those resources for those customers.

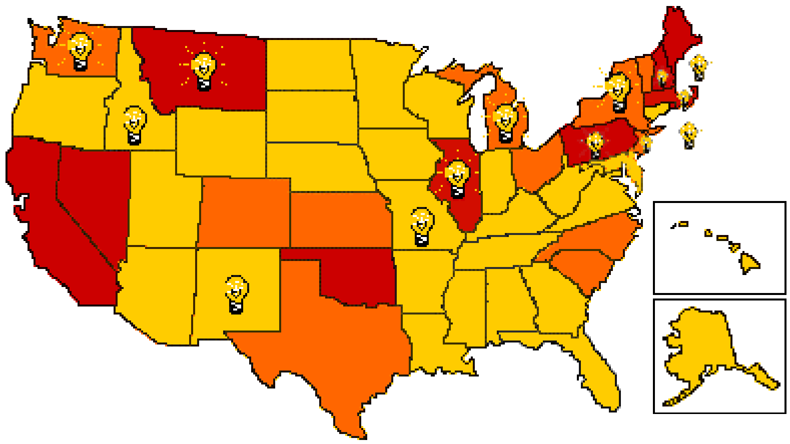
2.2 Retail market developments

2.2.1 Federal and state restructuring initiatives

Congress considered mandating retail access in its deliberations on the 1992 Energy Policy Act, but elected to defer the issue pending state action. Subsequently, federal restructuring legislation in various forms has been introduced but not yet seriously debated in Congress. Appendix 2.2 provides a comparison of some of the major features of the federal electric restructuring bills that have been introduced to date.

According to the Edison Electric Institute, all 50 states and the District of Columbia have initiated "legislative or regulatory processes examining retail competition, deregulation, restructuring, and/or alternative forms of regulation for the electric utility industry."[2] The National Regulatory Research Institute also confirms that all states have engaged in some restructuring-related activity.[3]

Figure 2.2 Status of Electric Utility Restructuring Activities



Retail Wheeling Legislation Passed
Retail Wheeling Legislation Proposed
Legislative or Regulatory Activity
Indicates states where pilot programs have been initiated or approved

Source: Strategic Energy Limited, http://www.sel.com/retail.html
This site includes links to detailed information on each state

The impetus for retail restructuring came largely from industrial customers in states with high power prices, like California and the New England states.[4] Seeing the growing disparity between retail power rates and the price of power in wholesale markets, these customers sought direct access to lower cost power supplies. Gaining this access generally meant changing state laws and/or regulatory requirements to compel utilities to deliver power from the provider of the customer's choice.

Even the first states to restructure are still in the early stages of implementing their restructuring laws or administrative orders. (A detailed comparison of state electric restructuring legislation provisions is provided in Appendix 2.3.) No meaningful conclusions can yet be drawn from the experience in these states with respect to the effect of retail restructuring on electric service costs. The prospects for future federal and state restructuring efforts and the pace of those efforts remain unclear.

It should be noted that Washington's electric power system is unique in its mix of federal, state, and local institutions and in the mix of authorities and responsibilities among those institutions. These unique features suggest that a model of restructuring that may work for states with less complicated systems may not be applicable in Washington. This is not to suggest that retail restructuring is impossible or undesirable, but rather that it raises a variety of unique issues that make it difficult to generalize from experience elsewhere. Washington is also unique in its mix of investor-owned and consumer-owned utilities. Most of the states that have restructured their retail markets have adopted different requirements for COUs and IOUs. Many of these states require IOUs to offer direct access but permit COUs to do so. However, COUs that do not elect to offer direct access are generally not permitted to sell to customers of utilities that do offer direct access.

Most of the arguments about whether retail restructuring will reduce electric service costs remain inconclusive. These arguments are briefly characterized in Section 3.2.

2.2.2 Retail market developments in Washington and the Northwest

At the end of 1996, the Comprehensive Review of the Regional Energy System recommended that the four Northwest states restructure their retail electric markets by July of 1998.[5] Montana is the only state to have enacted restructuring legislation and has begun to implement retail choice. Restructuring bills were considered by the Washington and Oregon Legislatures in 1997. (The Oregon Public Utility Commission is currently considering a restructuring plan filed by PGE/Enron.) The issue was considered again by the Washington Legislature in 1998, but no comprehensive restructuring bills were introduced. Bills requiring large utilities to account separately for the different components of electric service (HB 2831) and requiring state agencies to study various aspects and trends in the industry (ESSB 6560) were passed. This study is the product of the latter bill.

Although the Washington Legislature has not initiated any action to restructure Washington's retail electric market, that market is changing substantially. While utilities have not been compelled to deliver power from alternative providers, they are nevertheless experiencing and responding to significant competitive pressures and opportunities. Some of these changes, and some of their potential implications for electric service costs, are described below:

2.2.2.1 Pilot retail access programs

Several utilities have conducted pilot retail access programs, including Puget Sound Energy, Washington Water Power, and Clark PUD. Prices offered in pilots may bear very little relationship to prices in a system-wide retail access environment. Pilots have generally been structured to test operational issues, rather than to test the effects of competition on costs or prices.

2.2.2.2 "Non-traditional" rates

Most utilities have provided some form of either direct access or market-based rate schedule to their largest industrial customers. These have resulted in substantial recent declines in industrial rates. However, some customers are opting out of market-based rates and returning to conventional regulated service as wholesale market prices turn upward. We cannot judge whether this retail market activity has resulted in either cost reductions or cost shifts. To the extent that these customers enjoyed lower rates, this may be due to lower costs in the wholesale market that would have ultimately flowed through to retail customers even in the absence of market-based rates for industrial customers.

In response to the data survey for this study, fifteen utilities provided data on "non-traditional" rate offerings. These rates generally reflect either a market-based price or an agreement by the utility to purchase market power on behalf of the customer, as opposed to the traditional practice of charging rates based on the average cost to serve the customer class. The data indicate that cost pressure due to declining wholesale market prices can have a direct impact on utility rates, even in the absence of mandatory retail access.

Seven of these fifteen utilities offered "non-traditional" service to large customers in 1997. Five of the seven have seen participation in non-traditional service grow rapidly since 1995. A total of 418 customers were taking "non-traditional" service in 1997, accounting for nearly half the industrial load of the reporting utilities.

Figure 2.3 Share of Large Customer Load

	Share of Large Customer Load Taking Service Under "Non-Traditional" Rate Schedule
1995	*19%*
1996	*25%*
1997	*47%*

Source: ESSB 6560 Data Request

The average price at which "non-traditional" service was offered was 2.8¢ per kWh, more than half a cent lower than the average of the lowest industrial rate. This represents an average discount of 17% off the lowest reported industrial rate. The largest reported discount was 36% off the lowest industrial rate. The power products sold at these discounted rates may carry some price and supply risks.

Including these non-traditional rates, large customers have seen an average rate decrease of around 5% since 1995, while residential rates have remained relatively flat. Of the fifteen utilities reporting, thirteen reduced rates for their industrial customers between 1995 and 1997, and eight reduced the rates of their residential customers. Many of these were consumer-owned utilities that lowered rates following BPA's 1996 wholesale rate reduction. Industrial rates declined relative to residential rates for thirteen of the fifteen utilities. (The distributional impacts of non-traditional rates are discussed in Section 4.)

Figure 2.4 "Non-Traditional Service" Rate Information (Average of Reporting Utilities)

Average rate for "non-traditional" service(¢/kWh)	2.79
Average of lowest reported industrial rate (¢/kWh)	3.39
Absolute difference from lowest industrial rate (¢/kWh)	-0.60
Percent difference from lowest industrial rate	-17%

Source: ESSB 6560 Data Request

2.2.2.3"Diversification" of consumer-owned utility purchases

Many consumer-owned utilities took advantage of BPA's offer to "diversify" their resources by reducing their reliance on BPA in 1996. In some cases, they used this opportunity to offer market access or market-based rates to industrial customers. This was a way to pass through the benefits of low market prices without formal retail access. Diversification was also used by some utilities to make wholesale market purchases on behalf of all their customers.

2.2.2.4 Variations in tax exposure

By contracting directly with out-of-state suppliers, a few customers may avoid paying state and local taxes associated with utility service. We do not know how this may affect costs, since it either results in shifting of the tax burden or reduction in public services funded through taxes. Since the taxing jurisdiction presumably judges the benefits of those services to exceed the cost, reductions in those public services do not equate with reductions in cost. The present magnitude of this cost issue does not appear to be very large, unless and until more customers gain access to out-of-state suppliers. (See Section 4. See also Appendix 4.1 "Briefing Paper on Tax Policy and Restructuring the Gas and Electricity Industries," Washington Department of Revenue, November, 1998.)

2.2.2.5 Aluminum companies diversify supplies

The state's aluminum companies have diversified their resources and now purchase roughly 25% of their power from sources other than BPA. Like their BPA purchases, most of these purchases are untaxed at the state and local levels, as they do not flow through a retail electric utility. Since these purchases generally replace untaxed BPA purchases, they do not reduce tax revenues. These companies also have relatively new transmission contracts with BPA that give them direct access to the wholesale power market. The effect of this diversification on total costs, if any, is not known.

2.2.2.6 Declining achievement of energy efficiency, renewable resources, and low-income weatherization

Utility investment in energy efficiency, renewable energy, and low-income weatherization is declining rapidly. (See Section 9). While lower wholesale power costs explain some of this decline, much of it is due to competitive pressure on utilities to minimize rates. The rapid decline in BPA funding for these initiatives has generally not been offset by increased funding from retail utilities. Insofar as these investments secure cost-effective resources or otherwise produce benefits that exceed their costs, declining investment may raise total costs. For example, the Northwest Power Planning Council estimates that failing to capture cost-effective energy efficiency improvements that market forces will not capture would cost the Northwest region roughly $1.7 billion over the next 20 years.[6]

2.2.2.7 Competition and cost-cutting pressure raises concerns with respect to reliability

Reliability-related trends are discussed at length in Section 8 of this report. One concern is that pressure on integrated utilities to cut generation costs may cause underinvestment in maintenance and operation of delivery systems and thereby compromise their reliability. These utilities may also face uncertainty regarding their ability to recover the cost of reliability-related investments. We have no data on trends in reliability-related investments.

2.2.2.8 Transition costs

Some information suggests that utilities are experiencing costs associated with preparing for the possibility of greater competition in the future. For example, enhanced billing and metering technology, software changes, and the costs of compliance with HR 2831 and ESSB 6560 were all cited by utilities as costs related to competition or the prospect of competition. Data from California and the UK suggest that these transition costs may be significant in retail markets that have been legally restructured to provide open access.[7] We have no data on these costs in Washington, nor have we assessed what additional benefits may come from these investments.

2.2.2.9 Corporate realignment and reintegration

Investor-owned and consumer-owned utilities are engaged in a variety of mergers, acquisitions, realignments, and new partnerships to position themselves to take advantage of strengths, shore up vulnerabilities, and compete in new markets. Some large utilities appear to be focusing primarily on their wholesale marketing activities, while others are selling or plan to sell their generating assets to concentrate on expanding their range of activities in the retail market. Consumer-owned utilities including Chelan PUD and Snohomish PUD have formed marketing partnerships with investor-owned utilities or their affiliates. Public utilities are also beginning to provide and/or seeking authority to provide a wider range of services, including gas and telecommunications.

The effects of these trends on costs are far from clear. In general, mergers and acquisitions are nominally motivated by economies of scale or scope and the potential for cost reductions through the integration of complementary services. However, they may also be formed to take advantage of opportunities to exert horizontal market power. Some have expressed concern (and others have expressed hope) that partnerships formed for wholesale marketing may lead to wider access of consumers across the western grid to the benefits of low-priced resources that currently serve Washington consumers. (From a Washington perspective, this could raise costs; from a west-wide perspective, it could shift costs and benefits. Also, it should be noted that increased wholesale marketing of Northwest resources does not by itself redistribute the *benefits* of those resources. Unless existing laws and regulation that link Washington utilities and consumers to those benefits are changed or weakened, Washington consumers may benefit from increased wholesale marketing, insofar as wholesale revenues are credited against revenue requirements to lower retail rates.) Expansion of the range of services offered by consumer-owned utilities may lower costs for some services in some areas, but also raises concerns about competition between public and private service providers.

2.2.2.10 Uncertainty regarding cost recovery and market structure

Uncertainty regarding future market structure has consequences that may affect electric service costs as much as actual changes in market structure. For example, in the face of substantial uncertainties about their future customer base, utilities are generally disinclined to make long-term investments. To the extent that this disinclination is a considered response to uncertainties regarding such factors as technological change, it could tend to help minimize costs. (Washington has ample experience with long-term power investments that turned out to be unnecessarily costly.) However, to the extent that aversion to long-term investment reflects uncertainty about the legal and regulatory framework in which utilities will do business in the future, it may tend to increase costs over time. Such uncertainty could drive costs up and increase volatility by making it difficult to find capital for projects that ensure adequate supply, efficiency, and reliability in the future (See Section 2.3). Such uncertainty also tends to produce a bias against strategies with high proportions of capital costs to operating costs, even when those strategies are the least costly ones available. Without rendering judgement on how these trends will ultimately affect costs, it is worth noting that the concerns above are a function of uncertainty about future market structure rather than any particular change in market structure.

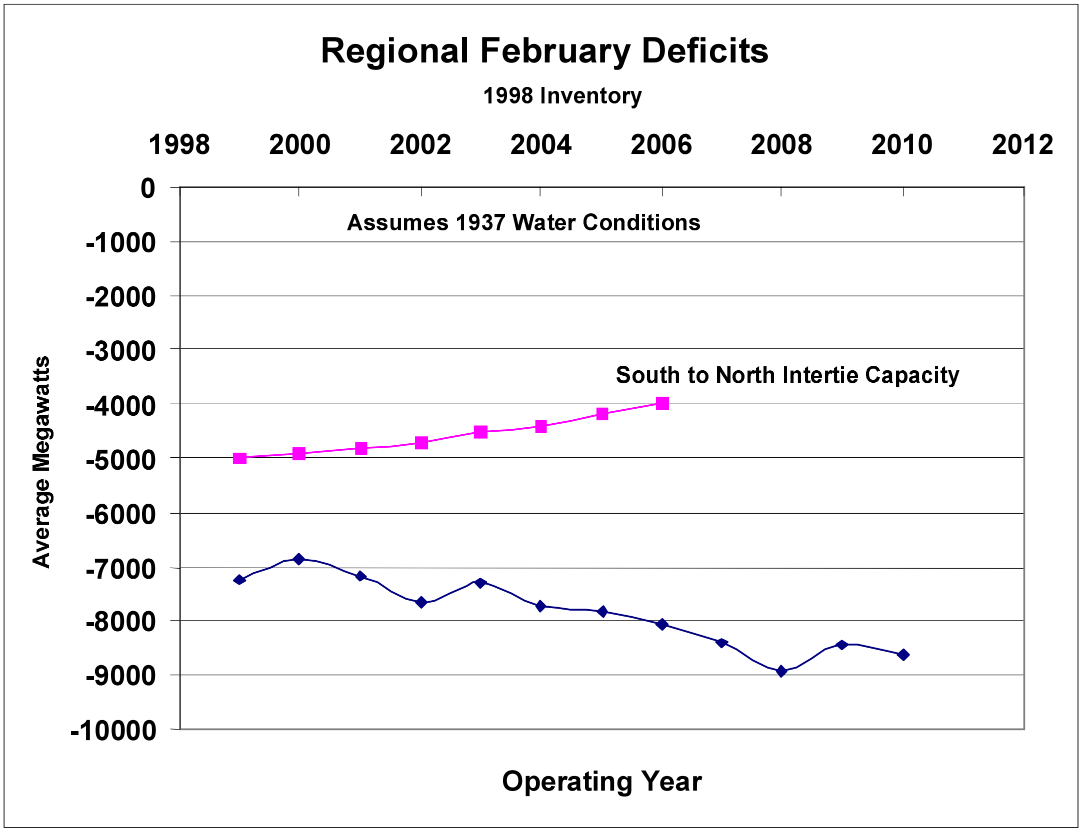
The changes described in 2.2.2 may affect not only the total cost of electric service, but also the distribution of costs, reliability, customer service, and environmental performance – many of the issues highlighted by the Legislature as sources of concern and study in ESSB 6560. This suggests that even if "restructuring" per se does not occur, many of the issues it raises are with us today.

2.3 Supply Adequacy and Reliability

Recent analyses of the Northwest's power system loads and resources indicate that in some months, the demand for electricity could exceed the region's current ability to generate and import power to meet regional loads. This analysis was presented in the Bonneville Power Administration's "White Book."[8] This issue is addressed as a reliability concern in Section 8. However, it is also a trend that may affect electric service costs, insofar as the means chosen to ensure supply adequacy and reliability may affect the cost of service.

Figure 2.5 provides a simplified view of the issue that was presented to the Northwest Power Planning Council. It shows the monthly regional deficits (current resources minus projected loads) that would occur in February with extremely adverse hydro conditions as represented by the conditions that existed in 1937. The bottom line depicts the region's power generation shortfall under such conditions. The top line depicts the approximate transfer capability of the North-South intertie, the main source of imported power. Its capability decreases with time as a result of load growth in the Northwest, which affects the ability to move power from south to north on the intertie. The growing gap between the two lines depicts the size of the deficits the region would experience under these very adverse water conditions. A similar but somewhat more severe problem exists when considering the ability to meet sustained peak loads. Those are the average loads during the peak ten hours per day for a five day work-week. During such a period, loads increase and generating capability may decrease due to extreme weather conditions.

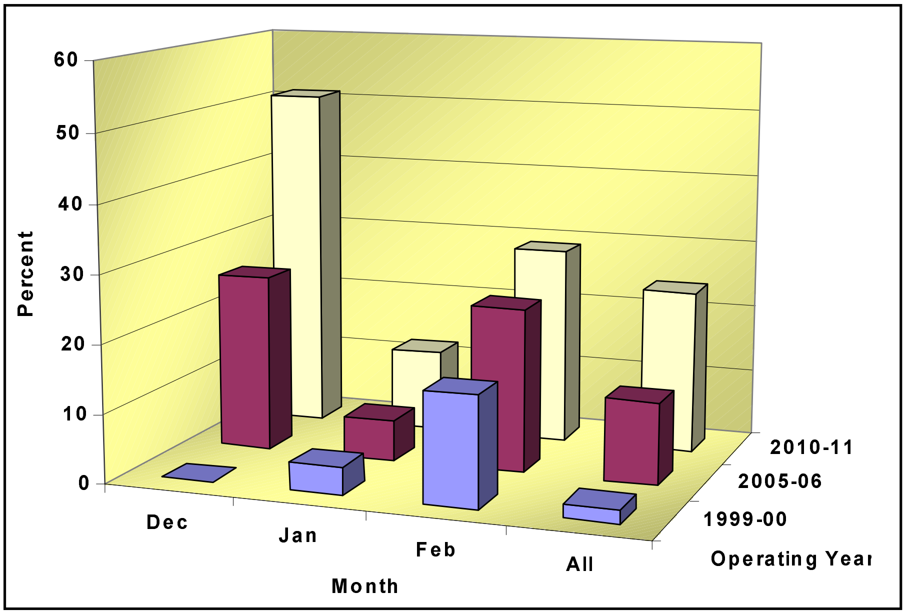
Figure 2.5 Regional February Deficits



The representation of the problem shown in Figure 2.5 is simplified in many respects. One of the most important is that it does not reflect the effects of year to year, month to month variations in hydro conditions. The Columbia River System cannot store the full annual runoff of the basin and the flexibility to use existing storage to maximize power production is increasingly limited. The difference in the hydro system's power capability from the driest to the wettest years is as much as 8000 average megawatts. These variations affect the probability that we will actually experience deficits in any given year.

To begin to assess the probabilities, Northwest Power Planning Council staff have looked at how frequently the regional deficit would exceed import capabilities in each of the winter months (December, January and February), based on the 50 water years in the historical record (1929-1978). This analysis was done for three different future operating years, assuming current regional resources and medium load growth. This is shown in Figure 2.6.

Figure 2.6 Probability of Monthly Energy Shortage



This figure indicates that for the 1999-2000 operating year, the likelihood of deficits in February is about 15 percent. By 2010-11, however, the likelihood of a deficit for December grows to roughly 50%. These deficits have been forecast for a few years now. But the magnitudes are increasing and the time available in which to take actions to avert a shortfall is becoming more limited.

In its preliminary look at this issue, the Northwest Power Planning Council reports that addressing these shortages is complicated by the changing nature of the utility industry. When utilities were less subject to competition, they acquired assets to provide an industry-standard level of reliability, including reserve generation and a robust transmission and distribution system. Regulators allowed investor-owned utilities to recover the cost of those assets in rates, even when some of those assets would be used very infrequently and cause increases in rates. With the prospect of competition, many utilities may be reluctant to include in their rates the cost of acquiring sufficient resources to serve loads that may have no obligation to remain on their system. To the extent that they are planning to meet future load growth, utilities increasingly rely on power purchases rather than constructing their own generation. Under the 1980 Regional Power Act, BPA has primary responsibility for meeting new regional loads when requested. However, many BPA customers no longer rely exclusively on BPA, and others question whether this is an appropriate role for a federal agency.

Additionally, a growing number of power suppliers are not regulated utilities but marketers or brokers who buy and sell power on the wholesale market without necessarily owning resources. Or they may be independent power producers without a captive customer base that assures them recovery of their fixed costs. Some utilities are selling off their generating assets. The result of these trends is increased risk for companies that acquire new generating resources.

This market risk may be compounded by the uncertainty associated with fluctuating output of the hydropower system. Developers have neither a stable market for the output of their resources, nor a guarantee that water conditions will be sufficiently unfavorable that their output is needed in any given month or year. This means that they may have to recover the costs of developing new resources over relatively short and highly unpredictable schedules of operation. The Northwest Power Planning Council has initiated an analysis to determine: 1) Whether existing market incentives are sufficient to bring about the development of new resources (generation, transmission or demand side); and 2) If market incentives are not adequate, what alternatives are there for ensuring the Northwest an adequate, reliable power supply?

The issue of generation adequacy and its affect on reliability is discussed further in Section 8.

2.4 Environment

Environmental costs are a significant component of the total cost of electric service. Power production of various types produces substantial air emissions, nuclear wastes, and significant impacts on water quality and quantity and river flow patterns. Since Washington relies primarily on hydropower, total air emissions from electric resources used to serve Washington consumers are relatively modest.[9] However, hydropower imposes other environmental costs, primarily in the form of damage to river ecosystems and particularly to anadromous fish. While it is difficult to quantify the economic value of hydropower's environmental impacts with precision, these costs are clearly a major factor in decisions about the region's existing and future electricity supplies. The financial cost and effectiveness of current and proposed measures to reduce these environmental costs are the subjects of intense debate.

In evaluating environmental trends that affect the cost of electric service, it is useful to distinguish between *internal* costs and *external* costs. Internal environmental costs are included in rates paid by consumers, such as the costs associated with installing air pollution control equipment or fish ladders. External costs are borne in the form of environmental damage such as habitat degradation or human health impacts.

This distinction between internal and external costs is important in order to clarify the difference between changes in the *amount* of environmental costs and changes in the *distribution* of environmental costs between internal and external categories. For example, measures required to support recovery of endangered salmon stocks may *shift* costs from the external category to the internal category. Prices may rise due to such internalization. However, such price increases do not generally reflect increases in total costs. Internalization of environmental costs increases total costs only if the cost of the mitigation measures exceeds the cost of the environmental damage mitigated. (This may be the case, for example, if the mitigation proves ineffective.)

It is often difficult or impossible to compare the cost of mitigation with the cost of environmental damage. However, when mitigation is required, society has implicitly made a broad, often political judgement that fixing or preventing the environmental damage is less costly than the damage itself. If we collectively do not accept this judgement, then pressure builds to change the laws or regulations that require mitigation. However, where we accept this judgement, then internalization associated with effective mitigation measures may tend to reduce costs, by sending price signals that more accurately reflect total costs.

The trends discussed below have implications for both the amount of environmental costs and the distribution of costs between external categories and internal categories. Many environmental trends may affect electric service costs. However, three trends seem most likely to have a substantial impact on the environmental costs of electric service in the foreseeable future: 1) declining populations and extinction of wild anadromous fish, 2) global climate change, and 3) increasing competition in electric power markets.

2.4.1 Declining populations and extinction of wild anadromous fish

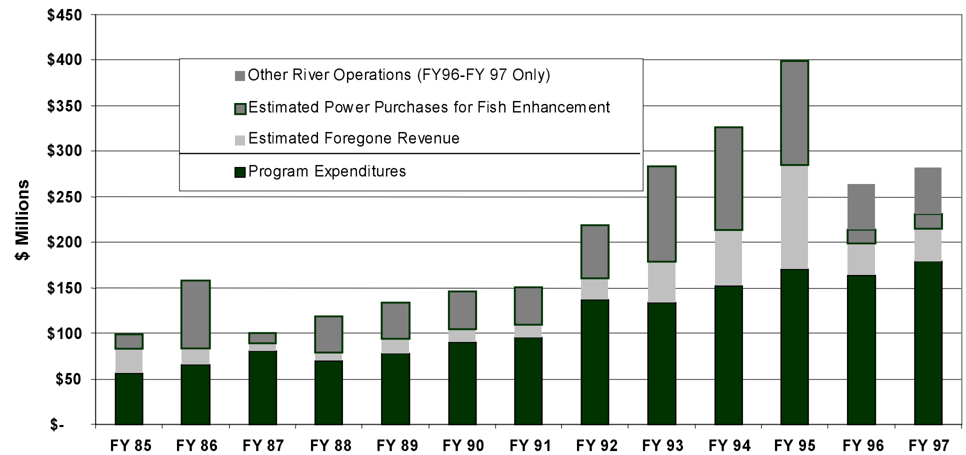
Many factors contribute to the decline of wild salmon and steelhead populations, including habitat destruction, recreational and commercial harvest, consumptive water uses, unfavorable ocean conditions, and competition between wild and hatchery stocks. On many rivers including the Snake and the Columbia, dams and hydropower production also appear to play a significant role in the decline of these populations. The trend in total environmental costs attributable to hydropower can be argued either way.

On the one hand, costs may be rising as genetically distinct stocks near extinction. When a run of fish approaches or falls below the threshold where it can continue to survive as a separate stock, additional costs are incurred in the form of lost genetic diversity, cultural values, and future economic opportunities.

On the other hand, improvements to fish passage facilities, flow regimes, hatchery practices, habitat management, and other biological conditions for fish in recent years suggest that some environmental costs have been mitigated. Many of these costs have been internalized in power rates. To the extent that these mitigation measures have been effective (a hotly contested issue), external environmental costs of hydropower production are presumably lower than they would have been without these measures. Whether the improved conditions attributable to these measures have been worth their costs is also a bitterly disputed issue, in light of continued decline of many wild stocks.

The dollar value of damage to fisheries from hydropower production cannot be assessed with precision. The cultural, biological, and esthetic values at stake are very difficult to quantify and value economically, and the precise affects of hydropower production cannot be definitively separated from other factors that adversely affect these stocks. However, it is clear that more environmental costs associated with anadromous fish decline are being internalized in power rates. The chart below shows the increases in BPA's fish and wildlife expenditures over time as reported in BPA's FY 1999 budget submittal.[10]

Figure 2.7 BPA Fish and Wildlife Costs



Sources: (1) 1985-1995 Data - Department of Energy, FY 1999 Congressional Budget Submittal, BPA, Fish and Wildlife Crosscut. (2) 1996-1997 Data - BPA White Paper, "What is BPA spending for fish and wildlife, March 1998. Available at http://www.efw.bpa.gov/Environment/EW/FISCAL/fiscal1.html
Notes: For FY85-FY 95: BPA Power Purchases for Fish Enhancement and "Foregone Revenues" from Source (1) For FY96 and FY 97: Power purchases, foregone revenue and other river operations from Source (2). FY85- FY 95 Program FY 85-For FY96 and FY 97: Power purchases, foregone revenue and other river operations from Source (2). FY85- FY 95 Program FY 85-FY95: Program expenditures include "Direct Fish and Wildlife Program,, "Reimbursable," and "Program Related Fixed Expenses" from Source (1) and FY96-FY97 "Direct fish and wildlife program,", "Reimbursables," and Debt service on capital investment" from Source (2).
Notes: Characterizing forgone revenue and power purchases as "fish and wildlife costs" is controversial. Such opportunity costs associated with irrigation, navigation, and flood control generally do not appear as budgeted "costs."

2.4.2 Global climate change

In 1995, the International Panel on Climate Change, a collection of 2000 of the world's leading climate scientists, concluded "the balance of scientific evidence suggests a discernable human influence on global climate."[11] While there is significant controversy about global climate change and its policy implications, the IPPC report documents a preponderance of scientific evidence on some aspects of the phenomenon, including the following:

- Global average temperatures have increased over the last century, with marked increases in the last decade;
- Concentrations of carbon dioxide and other heat-trapping gases in the atmosphere are increasing to unprecedented levels, due in part to human activities including burning of fossil fuels;
- Over the historic record, warming trends coincide with periods of high atmospheric concentrations of carbon dioxide.[12]

However, substantial uncertainty remains regarding the timing, magnitude, and local impacts of global climate change. This uncertainty cuts both ways: scenarios under which global climate could change dramatically and abruptly appear to be as likely as scenarios in which change is gradual and less disruptive.

Likely local impacts of climate changes are characterized in a 1997 report from the Joint Institute for the Study of Atmosphere and Oceans.[13] In the Pacific Northwest, the most significant effects may come from reduced snowpack due to warmer winter temperatures. More precipitation is likely to fall as rain in the winter and spring, causing more flooding early in the year and water shortages later in the year. Reduced snowpack means changes in the timing and reductions in the amount of hydropower production (which could be offset by reduction in winter space heating loads), reduced irrigation, warmer water temperatures and lower flows in the summer and fall. These conditions, along with higher ocean temperatures, may reduce the likelihood of salmon and steelhead recovery.[14] Significant impacts to forests, agriculture, coastal areas, and other ecosystems are also likely.[15] Some impacts from climate change may be beneficial. However, human systems are adapted to a relatively stable climate regime. Adaptations to rising sea levels, changed agricultural patterns, volatile weather, and other impacts may be costly.

Scientists indicate that global climate change is attributable to the increase in concentrations of various heat-trapping gases in the atmosphere ("greenhouse gases" or "GHG").[16] Emissions of these gases and their estimated relative contribution to global warming as a share of Washington's total contribution are depicted in the first chart below. The chart also depicts the relative contributions of different activities to GHG emissions in Washington. The following chart tracks GHG emissions by energy source over time.

Figure 2.8 Washington Greenhouse Gas Emissions

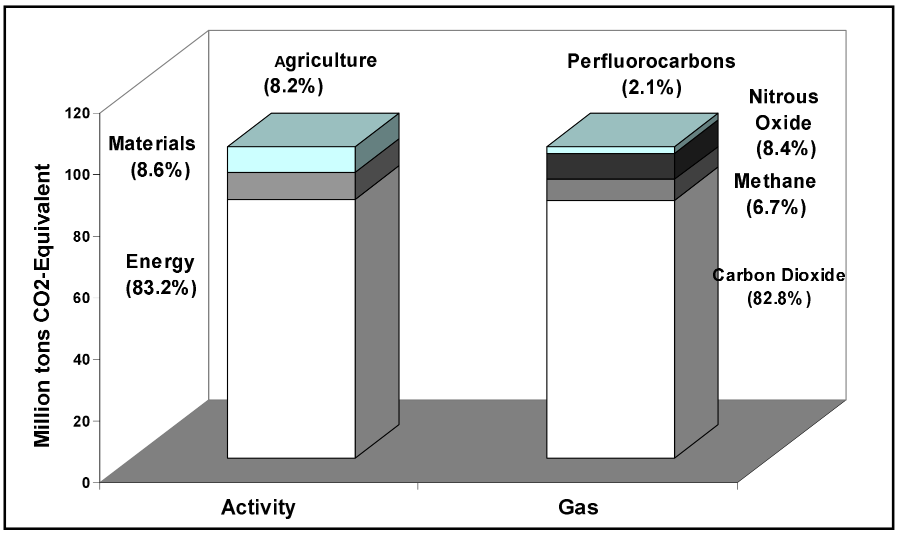
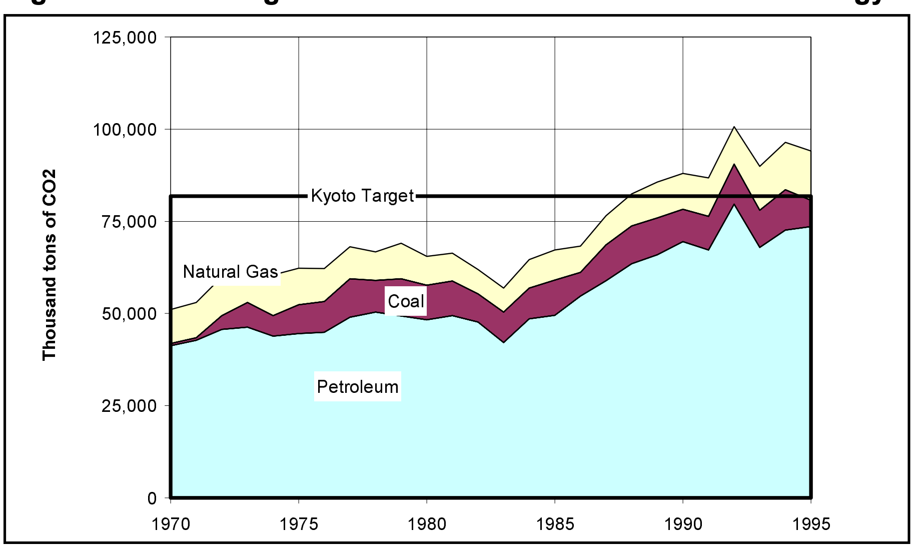


Figure 2.9 Washington Carbon Dioxide Emissions from Energy Use by Source



Transportation is by far the largest and fastest-growing source of greenhouse gas emissions in Washington. However, electricity production is a significant source of carbon dioxide. Most of the carbon dioxide produced by electric generators that serve Washington loads is produced by the Centralia and Colstrip coal-fired power plants in Washington and Montana, respectively. The 1997 Kyoto protocol, negotiated by more than 150 countries, would require the U.S. to reduce its GHG emissions to 7% below 1990 levels by 2008-2012. (Scientists indicate that substantially greater reductions [50-70%] would be necessary to stabilize the concentration of GHGs in the atmosphere.[17]) The U.S. Senate has not ratified the Kyoto Protocol. However, the agreement is a protocol to the United Nations Framework Convention on Climate Change ("Convention"), which President Bush signed and the Senate ratified in 1992. The non-binding U.S. commitment in the Convention is to reduce GHG emissions to 1990 levels by 2000.

Virtually all of the costs of climate change are presently external to electric power prices. Unlike other emissions, carbon dioxide is almost entirely unregulated, and few jurisdictions or utilities have incurred costs to mitigate it.[18] Even though most of our power comes from hydroelectricity, internalization of carbon costs in power prices could have a significant effect on prices in Washington, depending on how it is accomplished. (Here again, internalization of costs in prices does not equate to total cost increases, since higher power prices may be offset by lower external environmental costs.) For example, the Northwest Power Planning Council estimates that carbon taxes of $25 per ton would increase the price of electricity from coal and natural gas in the region by 2.3 cents per kWh and 1.2 cents per kWh, respectively.[19] Fuel switching away from carbon-intensive fuels may mitigate actual effects on power prices.

If and when the costs of carbon dioxide emissions are internalized, Washington's hydroelectric resources would become even more economically valuable relative to fossil-fueled resources. With some 85% of the region's electricity supplied by hydropower, internalization of GHG costs nationally or internationally could significantly decrease the price of power in Washington relative to other states and regions.

While global climate change is probably the most significant environmental trend related to air emissions from energy production, changing regulation of power plant emissions generally may also affect electric service costs. For example, compliance with tier 2 air quality standards of the Clean Air Act Amendments of 1990 will require some generators to reduce emissions of nitrogen oxides and fine particulates. Compliance may reduce health and environmental damages associated with these pollutants while raising the price of power from resources that must undertake mitigation measures.

2.4.3 Increasing competition in electric power markets

Growing competition in electric power markets can affect both the total environmental cost of electric service and the distribution of environmental costs between internal costs (included in power rates) and external costs (not included in power rates). Some of these potential effects are described below.

- *Insofar as competition focuses on minimizing electric power prices, it may increase pressure to increase external costs.* Since prices include only internalized environmental costs, price competition may tend to generate pressure to externalize environmental costs, or at least to avoid internalizing them. However, to the extent that environmental laws require mitigation of external costs, competitive pressure may lead to innovations that reduce the cost of complying with those laws.
- *Competition may tend to undermine utility investment in cost-effective energy efficiency and renewable resources.* Competitive pressure, along with other factors, appears to be reducing investment in and accomplishment of cost-effective energy efficiency and renewable resources. (See section 9). This may be due in part to the fact that conservation resources cease to be a utility asset if the customer in whose facilities the measures are installed switches to another provider. Also, while these resources may minimize total costs, they may not minimize rates, for two reasons. First, energy efficiency reduces consumption and thereby reduces the number of kilowatt-hours sold over which utilities spread their costs. Second, both energy efficiency and renewable resources tend to have lower environmental costs than conventional power sources. Since many of these costs are not included in rates, the environmental advantages of these resources do not improve their ability to compete on price.
- *Competition may increase the availability of "green power" for consumers willing to pay a premium for environmental quality.* "Green power" marketing has already begun in many places, including Washington. Some marketers use premium revenues from sales of "green power" for new investment in resources with low environmental cost or for mitigating environmental damage. This would tend to reduce environmental costs. Other green marketing programs redistribute the cost of existing resources to those consumers who express a willingness to pay more for them. This would not reduce environmental costs. Markets for green resources may tend to exhibit what economists call the "public goods" problem:[20] The environmental advantages of "green" resources are shared by everyone, regardless of whether they choose to pay more for those resources. And by the same token, those who pay more for "green" power must still bear the environmental costs of conventional resources. This public goods problem is the economic rationale for collective investments in military protection, transportation infrastructure, and other goods that cannot be secured in sufficient quantities through private investment alone.

2.5 Technology

Electric technology trends are discussed briefly below. While electricity technology has not been a major focus of legislative debate, it is a subject that may be worthy of somewhat more detailed analysis than the agencies have undertaken within the scope and time constraints of this study.

Technological innovations in both electricity-generating equipment and energy-using equipment have significantly reduced the cost of electricity over time. Ongoing technological changes are likely to include increases in the efficiency of generation, smaller and more distributed generating technologies, decreased production of criteria air pollutants, and growing interaction with information, communications and transportation technologies. These changes seem likely to decrease both internal and external costs of electric generation over time. New technologies are also likely to influence other costs of electricity operations through changes in metering and billing, load control, and greater utilization of infrastructure (e.g. cable or internet additions to power communications networks).

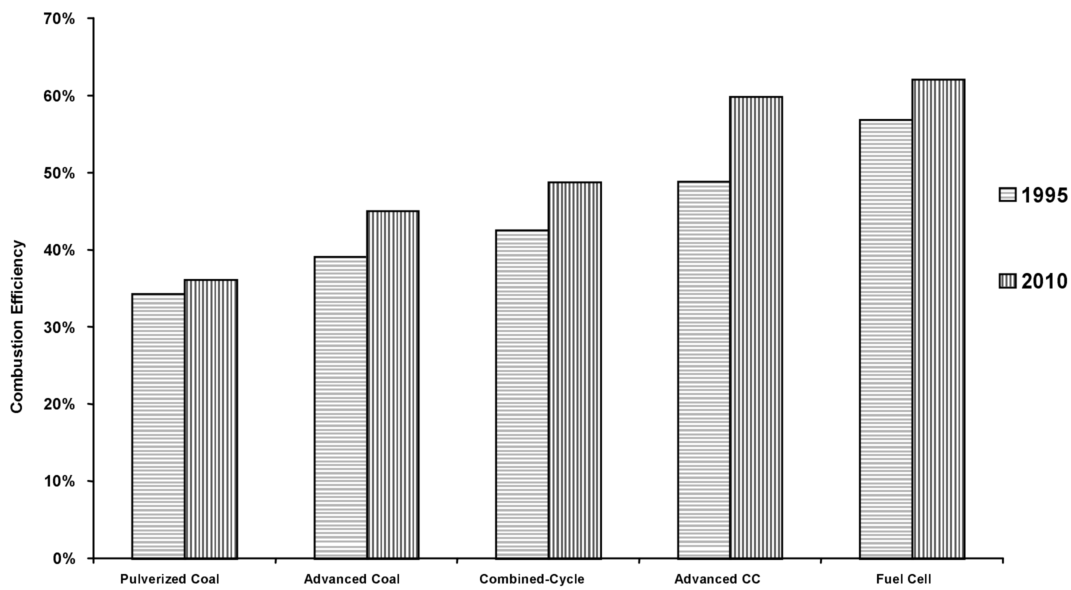
However, there are some indications that short-term competitive pressures may be squeezing out utility investments in research and development of energy technologies. (We have no data on trends in R & D expenditures for other electricity related industries, sulkch as equipment manufacturers.) One recent study finds that, "research and development funding by 80 of North America's largest investor-owned utilities fell by one-third between 1993 and 1996."[21] On average, industrial firms in the U.S. spend approximately 3.1% of sales on R&D. In 1994, US utilities, on average, devoted .3% of sales to R&D, and substantial reductions have occurred since then.[22] To respond to this situation, at least seven states with restructuring initiatives have included R&D among the categories of investment that are supported by a system benefits charge.

2.5.1 Natural Gas Combustion Turbines

The natural gas combined cycle combustion turbine is likely to remain the most common new generating technology for the immediately foreseeable future. The Energy Information Administration (EIA), in its 1998 Energy Outlook, estimates that 85% of new electricity generation from 1996 to 2020 will be combined-cycle or combustion turbine technology fueled by natural gas.[23]

Continuing advances in high temperature materials, coupled with improved turbine design and control technologies, will probably continue to push up the thermal efficiency of this equipment. The NWPPC uses a 0.5% per year increase in thermal efficiency for its resource projections. EIA reaches similar conclusions. Figure 2.10 illustrates EIA's projections for efficiency improvements for combustion turbines along with other comparable generating technologies. By 2010, the thermal efficiency of advanced combine cycle facilities is expected to increase from 49 % to 60%.

Figure 2.10 Combustion Efficiency of Electric Generating Technologies 1995 and 2010



Source: Energy Information Administration (EIA), Assumptions for the Annual Energy Outlook, 1997.
Note: Efficiency calculated based on actual (1995) and projected (2010) commercially available heat rates.

In addition to improved efficiency, the capital costs of new generating technologies are also likely to decline. EIA estimates that the capital cost components of advanced combined cycle units will decline from 7.5 mills/kWh ($1996) in 2005 to 7.2 mills/kWh ($1996) by 2020.[24] Capital costs represent about one-quarter of the total estimated cost of advanced combined cycle combustion turbines, so marginal reductions in capital cost will probably not be as important as fuel price trends in determining overall costs.

2.5.2 Distributed Technologies

Smaller scale distributed generation may assume a larger share of future electricity generation. Much research is underway on distributed technologies such as fuel cells, microturbines, photovoltaics (PVs), and advanced energy storage devices.[25] Advances in fuel cell technology are being driven rapidly by a number of factors, including the growing demand for clean transportation alternatives. Microturbines are likely to be sized at 25-75 kW, fuel cells from a few kW to a megawatt or more, and PV rooftop systems may be as small as a few kW each. Most of these technologies can be applied either as an additional component of the existing electricity grid or as stand alone, grid-independent systems. Estimates of the potential penetration of such technologies into the market range from as much as 20% of the new generation capacity additions over the next 10 to 12 years to only negligible contributions during that period.[26]

- **Microturbines:** Mass produced microturbines in sizes below 100 kW are now beginning to enter the market. Some of the likely applications include placement at the end of transmission and distribution lines to avoid high cost upgrades, installation as uninterruptible power supply units, and use as a dedicated prime mover for pumps, air conditioning, or process equipment. Many of the large manufacturers of conventional turbines and generators are developing microturbine product lines.
- **Fuel Cells:** Fuel cell technology is based on an electrochemical (rather than thermal) reaction between hydrogen and oxygen that produces direct current electricity and heat. The residual product from fuel cells is pure water. A wide range of feedstocks (including natural gas, coal, biomass) can subjected to a reforming process to extract hydrogen fuel for the cells. Successful development and production of fuel cells on a large scale could have major impacts on the costs and market structure of electricity production. Although currently too costly for most applications at 15 cents/kWh or more, they hold major promise for numerous future applications. Substantial research is underway on a wide range of fuel cell technologies including phosphoric acid, molten carbonate, alkaline, solid oxide, and proton exchange membranes.[27] Fuel cells are highly modular and can be manufactured in sizes from a few kW to several megawatts. Given the substantial investments in fuel cell research, it is likely that manufacturing cost and production costs will continue to decline.
- **Storage Devices:** Electric, chemical, and mechanical storage devices can serve as storage media in applications ranging from individual homes to utility systems. For utilities, new storage technologies can help increase utilization of transmission and distribution equipment, decrease reserve margins, allow for better integration of intermittent sources (such as wind and photovoltaics) into utility systems, and increase system reliability.[28] For electricity users, storage systems can increase power quality, provide uninterruptible power supply, provide storage and backup for intermittent renewable technologies, and reduce peak demand. Substantial research and development is under way to improve battery and flywheel technology. R&D is especially active in the area of low-cost, high power density batteries for transportation applications.[29] Flywheels offer the ability to store large amounts of energy at a high energy density. Improvements in materials, magnetic bearings, and vacuum chambers have reduced storage losses. Development of flywheels for utilities has focused on power quality applications.[30]

Figure 2.11 Distributed Generation Options

Technology	Size	Efficiency (%)	Cost Range
♦ Microturbines	25-100 kW	26-30	$300 - $400/kW
♦ Fuel Cells (numerous technologies)	200 watts – 5 MW	40 –65	$3000/kW
♦ Photovoltaic	<1 – 1000 kW	10-20	17-25 cents/kWh
Storage Devices			
♦ Battery Storage	500- 5000 kWh	70 –75	$400 - $1000/kW
♦ Flywheels	2-20 kWh	70 –80	$3000 - $6000/kW

Sources: EPRI Journal, March/April 1998. Cost range for U.S. DOE, Renewable Energy Technology Characterizations, “Overview of Energy Storage Technologies,” 1997.

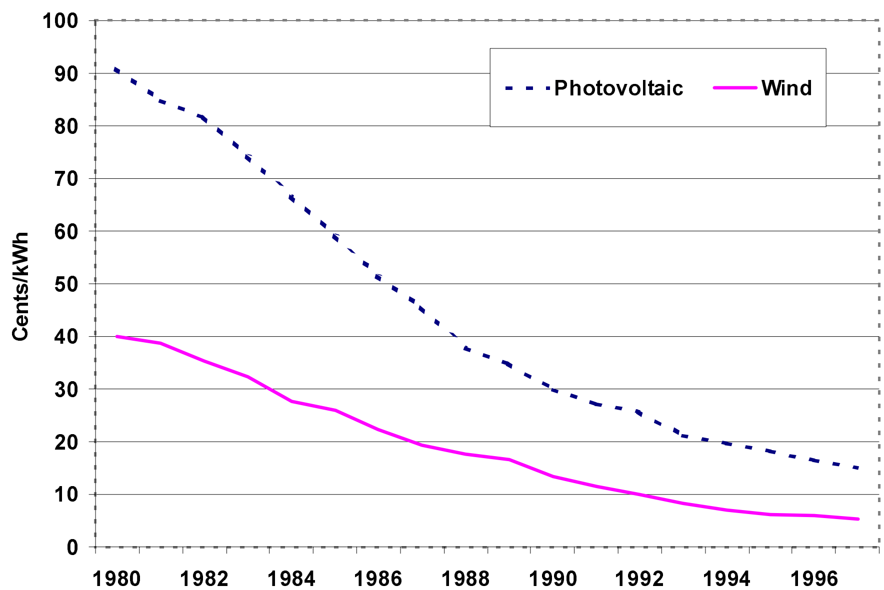
2.5.3 Hydroelectric generation

Hydroelectric generation is unlikely to increase in the U.S. overall and in the Pacific Northwest in particular. However, research and development are underway to improve the technology of hydroelectric turbines so that they are more “fish friendly” and can also operate more effectively under a wider range of water flow conditions. EPRI estimates that it will require 2 to 10 years for prototype development and testing of such improved turbines and development of variable speed, variable power turbines and controls.[31]

2.5.4 Renewable Technologies

Renewable energy technologies in addition to hydropower include wind, solar thermal, solar photovoltaic, geothermal, landfill gas and biomass. Currently the internal costs of these technologies are moderately to substantially higher than natural gas combustion turbines. Their external costs, however, are generally considered to be lower. The NWPPC’s 1996 cost estimates range from 4.1 cents/ kWh for wind to 17.8 cents/kWh for photovoltaic generation.[32] However, the costs of these technologies have declined significantly over the last two decades. Figure 2.12 illustrates this decline. Because some of these technologies lend themselves to distributed application, they are cost-effective in some remote applications now. For example, solar photovoltaics are a cost-effective option for pumping water for livestock in some areas.

Figure 2.12 Decreasing Costs of Renewable Energy Sources



Source: U.S. DOE, *Technology Opportunities to Reduce U.S. GreenhouseGas Emissions*, p. 2-37, 1998.

2.5.5 Cogeneration

Cogeneration or combined heat and power (CHP) is the simultaneous production of electricity and heat. Cogeneration allows for increased thermal efficiency through productive use of what would otherwise be waste heat from combustion. Cogeneration/CHP dates back to the early years of the electricity industry when small, localized power plants, predominately at industrial sites, produced both electricity and heat for industrial processes. As the size of generating plants expanded and large plants were often sited outside major population centers, cogeneration's share of electricity production waned. However, interest in cogeneration, both domestically and internationally, is again increasing. One factor driving this increase is the availability of small and clean distributed generation, which allows electric generators to be closer to heat-demanding processes or commercial loads. Overall efficiencies of 70 to 80 percent can make cogeneration very attractive to independent power producers and end users in some applications.[33] Because of the high thermal efficiencies it allows, cogeneration may contribute significantly to the achievement of carbon emission reduction goals. Washington currently has more than 680 MW of installed cogeneration capacity.

2.5.6 Energy-using equipment

Just as improvements in electricity generating technology have steadily increased the conversion efficiency of electricity production, technological improvements in electricity using equipment have significantly increased end use efficiency. Over the last 25 years, the development and adoption of building energy codes, implementation of large scale utility conservation programs, national appliance and equipment efficiency standards, and state conservation efforts have driven technological innovation. High efficiency motors, windows, electronic ballasts, and sophisticated energy management systems are a few of the many new electricity-saving devices. These technologies have reduced the cost of electric service by displacing the need for more costly new supplies and lowering operating costs for residential, commercial, and industrial equipment.

The NWPPC estimates that cumulative savings from energy efficiency programs in the region amounted to about 1,000 average megawatts in 1996. The Council estimates that the region still has approximately 1,535 average megawatts of cost-effective conservation potential available at an average levelized cost of 1.7 cents/kWh. Much of this potential involves increased commercialization of energy saving technology.

Figure 9.4 in Section 9 shows the decline in the electricity intensity of Washington's economy (the amount of energy used to produce a given amount of economic output) in real dollar terms. Technological improvement is one of the factors contributing to this decline.

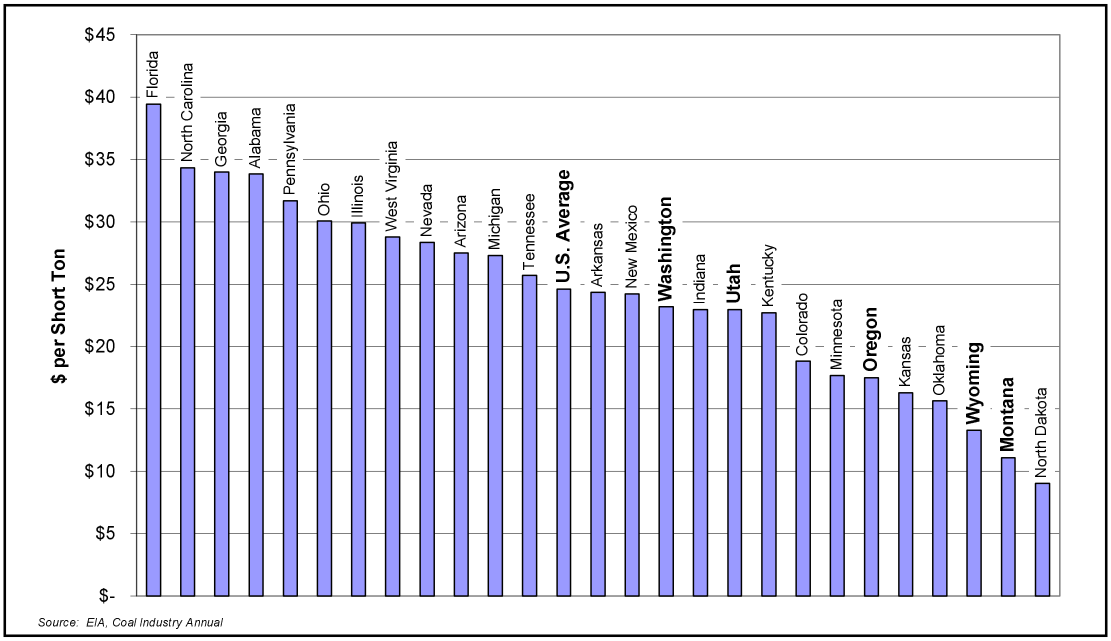
2.5.7 Communications and information technology

Communications and information technologies present substantial opportunities to reduce electric service costs and expand product and service diversity. These technologies allow for remote meter reading, real-time pricing, direct load management, and remote monitoring of energy efficiency or power quality.[34] Remote meter reading is likely to be the most significant near-term application, allowing utilities to decrease their operating costs while linking them more closely to their customer base. Such enhanced links also open up the opportunity for energy service providers to form new partnerships and to provide new services.

2.6 Fuel

Washington's primary reliance on hydroelectric power has tended to insulate it to some degree from trends in the price of fossil fuels. However, a significant portion of the power consumed by Washington citizens comes from large, coal-fired power plants that were built in the 1970s. Moreover, almost all new generating capacity that has been installed in the 1990s has been fired with natural gas, and gas appears to be the resource of choice for the foreseeable future. Fuel prices are likely to play a growing role in determining the price Washington consumers pay for electricity.

Figure 2.13 Coal Prices to Electric Utilities, Selected States, 1997



Fuel prices in the Northwest tend to be lower than in the rest of the country. Figure 2.13 compares coal prices at electric utilities in selected states around the country. The boldface type indicates states in which coal plants owned by utilities serving Washington customers are located. Wyoming and Montana, where the bulk of the Northwest's coal-fired generating capacity is located, enjoy some of the lowest coal prices in the country. This is due both to the characteristics of the resource (the coal tends to lie close to the surface and be low in sulfur) and to the location of the generating plants at the minemouth, reducing the cost of transporting the fuel. Centralia coal is cheaper than the national average.

Figure 2.14 Natural Gas Prices at City Gate, Selected State and Census Divisions, 1996

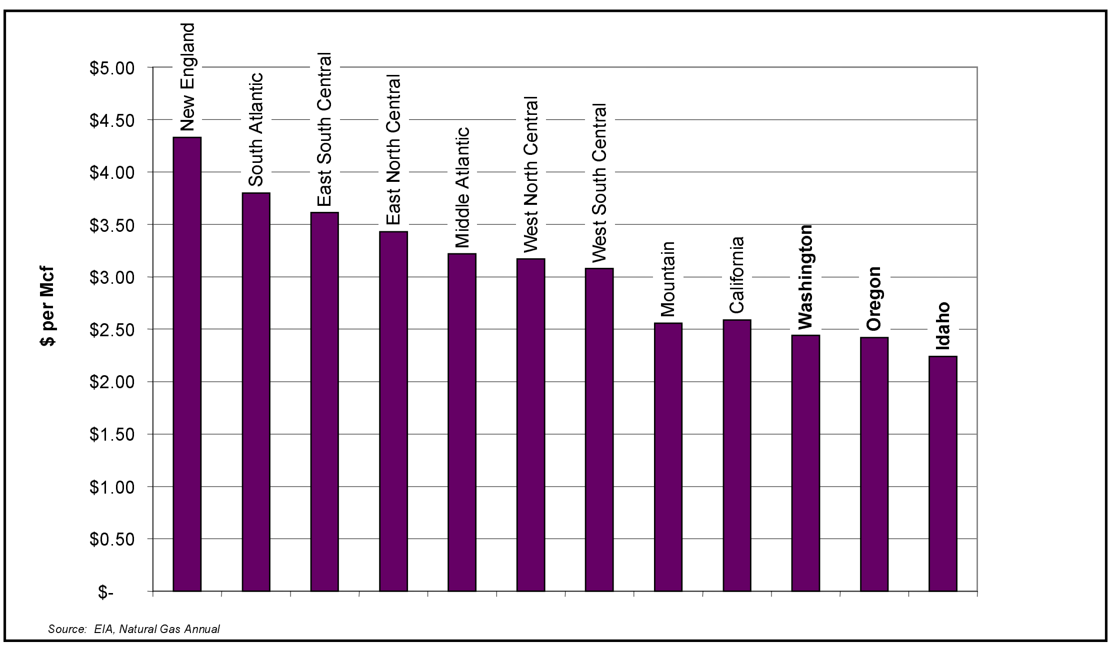
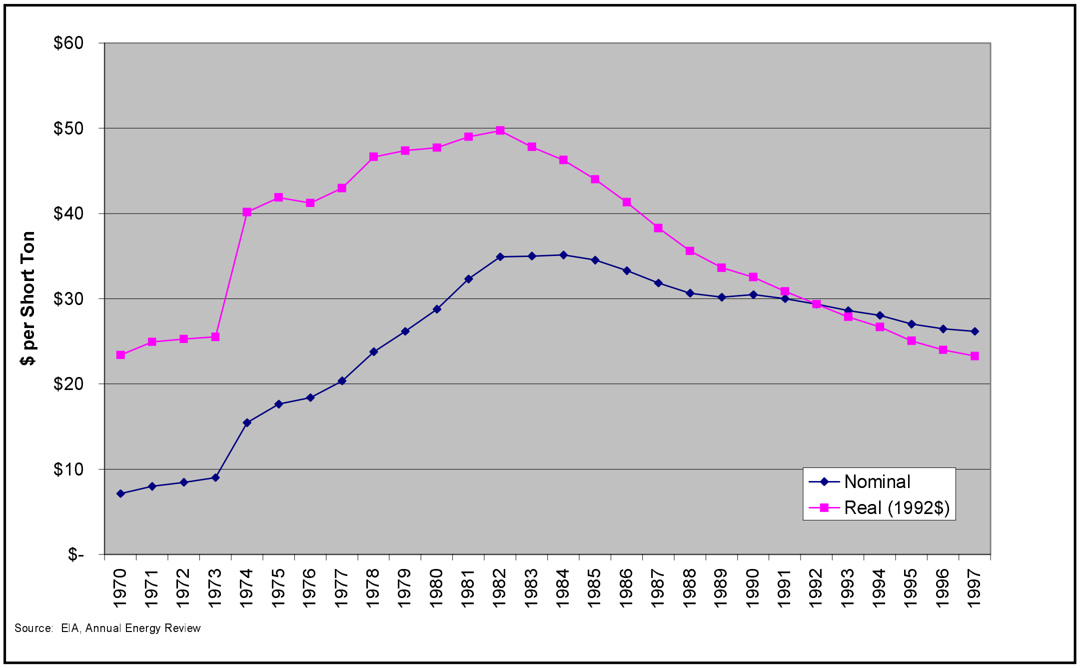


Figure 2.14 compares city gate natural gas prices in selected states and census divisions. Washington, Oregon and Idaho enjoy some of the lowest natural gas prices in the country, even lower than in gas-producing regions like the West South Central (which includes Oklahoma, Texas and Louisiana). This is due primarily to the availability of cheap Canadian supplies, and secondarily to inexpensive production in Wyoming and northwestern Colorado. There is some question about whether this cost advantage will continue. Several projects are in the works that may decrease this cost advantage by increasing pipeline capacity from the Rocky Mountain region eastward, both in the U.S. and in Canada.

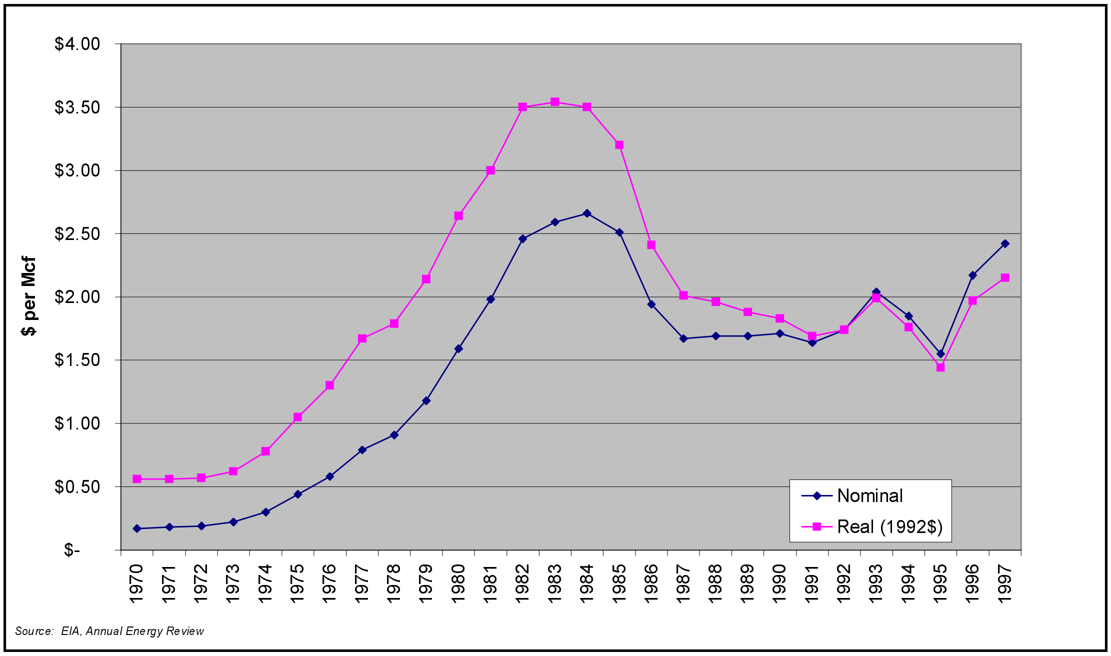
The next two charts examine the trend of fuel prices over time, both in real and in nominal terms. Prices for coal and natural gas have exhibited similar trends over the past thirty years or so. Both were cheap in real terms in the early 1970s, and both saw steep price increases throughout the 1970s. Coal prices across the country have declined steadily since, peaking at around $35 per ton in 1982-1984. The average price in 1997 was $26.16 per ton. In real terms, prices for coal delivered to electric utilities are less than half what they were fifteen years ago.

Figure 2.15 US Coal Prices to Electric Utilities, 1970-1997



The story is similar, though more pronounced, for natural gas. Gas prices skyrocketed in the 1970s, increasing over 500% in real terms between 1970 and 1983. Production increases, infrastructure improvements, and regulatory changes led to much lower prices by the late 1980s, and prices fell to less than half their former levels in the mid-90s. The last three years have seen gas prices drifting back upwards. It remains to be seen whether this becomes a long-term trend.

Figure 2.16 US Wellhead Natural Gas Prices, 1970-1997



Both natural gas and coal are fossil fuels with substantial environmental impacts, primarily in the form of air emissions. The costs of these impacts are not fully internalized. Burning coal produces harmful air pollutants including oxides of nitrogen (NO and NO_2, or NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO), as well as ash, fine particulates, and heavy metals such as mercury and arsenic. Burning natural gas produces no particulates or heavy metals, but does produce NO_x and CO. Both fuels produce carbon dioxide, the most prevalent greenhouse gas. In general, and particularly in the case of carbon dioxide, coal-fired generators produce substantially greater emissions per unit of energy than do gas-fired units.

While some of these environmental costs have been internalized through fuel switching or the installation of pollution control equipment, increasing environmental liabilities are a factor that is likely to affect future fuel prices. For example, the coal industry is still in the process of complying with Phase I of the Clean Air Act Amendments of 1990, which require a 60% reduction in industry-wide SO_2 emissions by 2010. The Energy Information Administration has estimated that the cost to utilities of complying with Phase I of the 1990 CAAA has amounted to $836 million per year, in 1995 dollars.[35] Compliance with Phase II, which begins in 2000, will also be costly. Minemouth coal may continue to get cheaper, but burning it will probably continue to get more expensive.

Efforts to reduce greenhouse gas emissions may put upward pressure on fuel prices. The electric utility sector accounts for approximately one third of U.S. greenhouse gas emissions, and may be called upon to achieve a substantial portion of greenhouse gas emission reduction targets. Some internalization of carbon costs may be required in order to achieve significant greenhouse gas reductions. This internalization would increase the price of electricity in proportion to the carbon emitted by the generation source, with the greatest increases falling on coal-fired power. By the same token, it would increase the relative price advantage of renewable resources, including the hydropower that provides most of Washington's electricity supply.

Carbon emission reduction efforts would probably also affect natural gas prices. Electric utilities may substantially increase their use of natural gas in an effort to reduce emissions from coal plants. This would put pressure on gas supply and cause prices to increase. Natural gas also contains carbon and would presumably be subject to any policy that internalizes carbon costs.

Endnotes for Section 2

[1] See, for example, Senate Bill 2499 in the 105th Congress.
[2] "Retail Wheeling and Restructuring Report," Edison Electric Institute, June 1997.
[3] National Regulatory Research Institute "Electric Industry Restructuring Box Score"; http://www.nrri.ohio-state.edu
[4] The average price of electricity in the 17 states that had mandated retail competition as of May 1998 was 8.6 cents/kWh, compared to an average price of 6 cents/kWh in the other states. ("Creating Competitive Markets in Electric Energy: A Critical Analysis of H.R.655" *Electricity Journal,* May 1998)
[5] "Comprehensive Review of the Northwest Energy System Final Report: Toward a Competitive Electric Power Industry for the 21st Century," December 12, 1996.
[6] *Fourth Northwest Conservation and Electric Power Plan*, Northwest Power Planning Council, 1998
[7] On May 13, 1998, the *San Francisco Examiner* reported that California utilities would ask to recover $979 million for costs incurred to initiate retail competition through 2001. In the August/September 1998 issue of *Electricity Journal,* Alex Henney reports that the transaction costs for initiating competition in the U.K. exceed $1.5 billion.("Contrasts in Restructuring Wholesale Electric Markets: England/Wales, California, and the PJM")
[8] *1997 Pacific Northwest Loads and Resources Study,* the Bonneville Power Administration, December 1997.
[9] Nationally, however, electric power generation accounts for two thirds of total emissions of sulfur dioxide, one third of total emissions of nitrogen oxides, and one third of total emissions of carbon dioxide.
[10] The agencies did not collect comparable data on internalization of fish costs from other hydropower operators, but anecdotal evidence suggests significant increases in recent years for many hydropower facilities.
[11] IPCC Second Assessment, Climate Change 1995, Intergovernmental panel on Climate Change. United Nations
[12] D. Raynaud et al., "The Ice Core Record of Greenhouse Gases," *Science,* 259, 1993, pp. 926-34
[13] Snover, Amy, Edward Miles, and Blair Henry, OSTP/USGCRP Regional Workshop on the Impacts of Global Climate Change on the Pacific Northwest, NOAA Climate and Global Change Special Report No. 11, March 1998.
[14] See, for example, "Thermal Limits and Ocean Migration of Sockeye Salmon: long-term Consequences of Global Warming," *Canadian Journal of Fisheries and Aquatic Science*, Volume 55, 1998, D.W. Welch, Y. Ishida, and K. Nagasawa.
[15] Snover, et al
[16] IPCC Second Assessment Climate Change, 1995
[17] IPCC, Second Assessment
[18] Last year, Oregon began to internalize carbon dioxide costs when it incorporated carbon emission standards in its energy facility siting statute. Under the new law (HB 3283), electric generating facilities sited in Oregon must mitigate carbon emissions to a level 17% lower than the most carbon-efficient power plant operating in the U.S. at the time the new plant is permitted. This can be accomplished through emission reduction at the plant or payment of $0.57 per ton of carbon into a fund for carbon mitigation projects.

[19] Northwest Power Planning Council, *Draft Fourth Northwest Power Plan,* Table 6-3
[20] See Hardin, Garrett, "The Tragedy of the Commons," *Science*, 162 1968. pp. 1243-1248
[21] "Changes in Electricity-Related R&D Funding," US General Accounting Office, August 1996 GAO/RCED-96-203
[22] "US National Investment in Energy R&D: 1974-1996", JJ Dooley, PNNL-11788, December 1997
[23] Energy Information Administration, *Annual Energy Outlook 1998 with Projections Through 2020,* DOE/EIA-0380(98), December 1997, page 51.

[24] EIA, *Outlook 1998,* page 52.
[25] EPRI Journal, "Emerging Markets for Distributed Resources," March/April 1998
[26] EPRI Journal, "Emerging Markets…"
[27] See for example, Avista Labs of Spokane at http://www.avistalabs.com/home/index.html for information on fuel cell research.
[28] U.S. DOE, Renewable Energy Technology Characterizations, "Overview of Energy Storage Technologies," 1997 at http://www.eren.doe.gov/utilities/techchar.html.
[29] See for example, "Study Progress: Electric-Car Batteries Are on Track," Electric Power Research Institute, 1998.
[30] "Energy Storage Technologies," Appendix A, U.S. DOE, Renewable Energy Technology Characterizations, 1997.
[31] Electric Power Research Institute, *Powering Progress, The Electricity Technology Roadmap Initiative. Background Report: A Preliminary Vision of Opportunities,* August 1997, page 2-16.
[32] NWPPC, *1996 Plan,* Table 6-1, page 6-5.
[33] Tim Hennagir, "CHP's Promise," Independent Energy, January/February, 1998.
[34] Michael Kintner-Meyer, "Communication Technologies for Energy Management and Energy Services" ACEEE Summer Study, 1998, page 8.204
[35] EIA, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, April, 1997, available on the EIA website: http://www.eia.doe.gov/cneaf/electricity/clean_air_upd97/exec_sum.html